Attachment A

Assessment of Available Technology for Control of NOx, CO, and VOC Emissions from Biogas-Fueled Engines – Preliminary Draft Final Report

INTRODUCTION

Rule 1110.2 establishes emission limits of NOx, VOC, and CO from stationary, non-emergency gaseous- and liquid-fueled engines, including the 55 engines in this source category that are fueled by landfill or digester gas (biogas). The emissions from biogas engines amount to approximately 0.93 tons per day of NOx and 0.44 tons per day of VOC.

Rule 1110.2 was amended on February 1, 2008 to lower the emission limits of natural gas and biogas engines to BACT levels for NOx and VOC and to levels close to BACT for CO. The limits for natural gas engines at or above 500 bhp took effect on July 1, 2010, while those for natural gas engines below 500 bhp took effect on July 1, 2011. Biogas engines were given until July 1, 2012 to comply with the new limits.

Table 1. Current and Future Biogas Engine Emission Limits (ppmvd @15% O_2)

	NOx	**VOC**	**CO**
≥ 500bhp	36 x ECF*	250 x ECF* (digester) 40 (landfill)	2000
< 500 bhp	45 x ECF*	250 x ECF* (digester) 40 (landfill)	2000
Future limits	***11***	***30***	***250***

*ECF is the Efficiency Correction Factor

The emission levels above are based on BACT limits for lean-burn natural gas engines which, in g/bhp-hr, are 0.15 for NOx, 0.6 for CO, and 0.15 for VOC. The current BACT limits for biogas engines are much higher. Expressed in g/bhp-hr, they are 0.6 for NOx, 2.5 for CO, and 0.8 for VOC. Figure 1 highlights this difference.

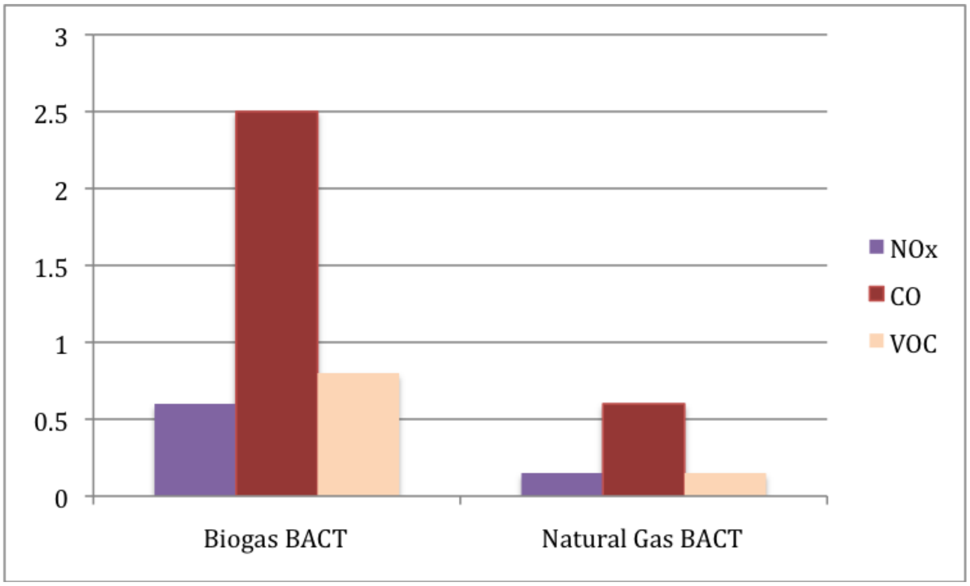


Figure 1. Biogas vs. Natural Gas BACT in g/bhp-hr

The BACT limits for lean-burn natural gas engines have been in effect for many years and many installations are complying with these limits by way of oxidation catalysts for CO and VOC control and selective catalytic reduction (SCR) for NOx control.

The amendment and adopting resolutions of Rule 1110.2 in 2008 directed staff to conduct a Technology Assessment to address the availability, feasibility, cost-effectiveness, compliance schedule, and global warming gas impacts of biogas engine control technologies and report back to the Governing Board no later than July 2010. Immediately after the 2008 amendment, staff began work on the Technology Assessment and followed the progress of several technology demonstration projects.

1. *OCSD.* A year-long pilot study utilizing a digester gas cleanup system (non-regenerative) and catalytic oxidation with selective catalytic reduction.

2. *EMWD.* Two technologies applied to water and wastewater treatment applications. One technology (NOxTech) was installed at a pumping station with three natural gas-fired engines. The other technology utilizes fuel cells to produce power from a wastewater treatment facility that produces digester gas.

3. *IEUA.* Fuel cells are set to be installed at this digester gas facility to eventually replace the IC engines currently installed.

4. *Ox Mountain*. This installation in the Bay Area uses biogas cleanup, catalytic oxidation, and SCR to produce power from landfill gas. The technology is similar to OCSD's in its post combustion after treatment, but uses a regenerative siloxane removal system to clean the landfill gas.

In July 2010, staff presented to the Governing Board an Interim Technology Assessment which summarized the biogas cleanup and biogas engine control technologies to date and the status of on-going demonstration projects. Due to the delays caused by the permit moratorium in 2009, the release of another report was recommended upon the completion of these projects. The Interim Technology Assessment concluded that feasible, cost-effective technology that could support the feasibility of the July 2012 emission limits is available, but that the delay in the demonstration projects would likely necessitate an adjustment to the July 1, 2012 compliance date of Rule 1110.2.

The proposed amendments for Rule 1110.2 provide an adjustment to the July 1, 2012 compliance date. Since July 2010, District staff has received ample evidence in support of the feasibility of biogas engine control technology and the feasibility of the compliance limits to complete the Technology Assessment. This Preliminary Draft Final Technology Assessment discusses the technologies pertinent to biogas engines for complying with these emission limits.

BIOGAS CLEANUP

For natural gas engines, the use of catalyst after-treatment is an effective method for pollutant control. Rule 1110.2 allowed higher emission limits because of catalyst fouling when exposed to the combustion products from biogas engines. But it was learned that the cause of the catalyst fouling was due to a specific impurity in the gas stream. These impurities are now known as siloxanes.

In the 2008 Interim Technology Assessment, the impacts of siloxanes were highlighted and evaluated in terms of facility-specific levels and control costs. The conclusion was that in installing an appropriately designed biogas cleanup system, an engine along with its post-combustion control system can function properly.

A prime concern for many biogas engine operators is the quality of the fuel going into the engines. Biogas, whether coming from a wastewater treatment plant digester or from a landfill, has many impurities, including but not limited to sulfur-containing compounds and siloxanes, that require some sort of treatment. If left untreated, raw biogas can damage engine components that will require more maintenance and ultimately, reduce the longevity of the engine. Siloxanes can crystallize and become deposited in fuel lines and engine parts. As a result, more frequent major maintenance on engines is required so that deposits from untreated biogas can be cleaned up from within the engine. Failure to perform this kind of maintenance can result in catastrophic damage to an engine. The pretreatment of biogas is even more critical with the employment of catalyst-based after-treatment technologies downstream from the engines. If left untreated, impurities such as siloxanes can result in the rapid poisoning of the catalyst downstream of the engine. The active sites of the catalyst become masked by the deposition of silica, therefore reducing the efficiency of the entire catalyst.

Since the release of the Interim Technology Assessment and the installation of several biogas cleanup systems in the basin, it has been established that biogas cleanup cannot consist of siloxane removal only. Depending on the source of the raw biogas, some facilities have biogas profiles that contain varying levels of other pollutants, such as VOCs and sulfur compounds. Also, with the installation of fuel cells in the basin, the fuel specifications for these sophisticated units are extremely stringent for impurities. Biogas entering a fuel cell must be completely cleaned of many impurities to guarantee proper performance.

Some facilities currently have practically no gas cleanup while most others employ some sort of gas cleanup for improved engine maintenance. On the other hand, a few facilities already employ a complete biogas cleanup system for protection of post combustion catalysts or turbines. Many facilities often utilize a typical cleanup system that results in moisture and particulate removal. The previously mentioned demonstration project at the Orange County Sanitation District (OCSD) utilized the facility's existing compressors, while relying on a single activated carbon vessel as the sole source for siloxane removal. This digester gas cleaning system (DGCS) was installed (supplied by Applied Filter Technology) to remove contaminants from the digester gas before combustion and the potential for carbon media breakthrough was routinely monitored throughout the pilot study. Depending on the existing level of contaminants, some facilities may have to install complete, skid-mounted gas cleanup systems that will include water and particulate removal filters, sorbent vessels for H_2S and siloxane removal, compressors, chillers, coalescing filters, and vessels for VOC and sulfur species removal if necessary.

As described in the Interim Technology Assessment, there are two types of siloxane removal systems, regenerative and non-regenerative. Regenerative siloxane removal systems do not require constant removal of the sorbent material from its vessel. It is regenerated using a heated purge gas, while a second vessel handles the siloxane cleanup load. The regenerative siloxane removal system at Ox Mountain Landfill remains the only installation that currently uses this type of system for the protection of a post-combustion catalyst. Ox Mountain Landfill is located at Half Moon Bay, CA which is within the Bay Area Air Quality Management District's (BAAQMD) jurisdiction. The landfill gas to energy site (operated by Ameresco) has six GE-Jenbacher engines, each rated at 2677 bhp, that are fired on landfill gas. All six engines have been retrofitted with oxidation catalysts, while one of the engines also has an SCR system. The gas cleanup system with regenerative siloxane removal processes the gas for all the engines. It employs a Temperature Swing Adsorption (TSA) regenerative siloxane removal system manufactured by GE-Jenbacher. Two adsorption beds of regenerative activated carbon are alternatively regenerated by using heat. The gas cleanup and oxidation catalyst/SCR was commissioned in 2009 and has shown to be very effective in the removal of siloxanes from the landfill gas. Performance data shows that the system is removing between 95 and 99 percent of inlet siloxanes.

Non-regenerative siloxane removal systems require periodic replacement of the sorbent material (activated carbon or silica gel) once it is spent. Additionally, the use of two beds is more beneficial in that one bed can still be used while the other is recharged with fresh sorbent and vice versa. These kinds of systems are sized to handle the site-specific siloxane load; higher amounts of sorbent are required for biogas streams with higher levels of siloxanes and must be able to handle intermittent spikes.

The demonstration project at OCSD has proven that a non-regenerative siloxane treatment system can handle biogas and protect biogas engines and post combustion catalysts. The gas cleanup system removed siloxanes, VOC, and sulfur compounds effectively without any breakthrough to the engines. An added benefit was realized in that there was a reduction in the engine maintenance due to the cleaner biogas that was being combusted. Furthermore, the result is a cost savings for engine maintenance, increased engine uptime, and longer maintenance intervals. The OCSD demonstration project saved $43,547 in engine maintenance costs annually with the use and careful monitoring of the gas cleanup system. Additionally, the gas cleanup system from its catalytic oxidizer pilot study in 2007 is still in operation today based on the performance improvements to the engine and the reduce maintenance costs.

With the demonstration project at OCSD completed and the installation at Ox Mountain in its third year, the employment of both regenerative and non-regenerative siloxane removal systems for the protection of post-combustion catalyst has been proven to be feasible. Performance data from both installations demonstrates effective siloxane removal for both digester and landfill gas applications.

CATALYTIC OXIDATION/SELECTIVE CATALYTIC REDUCTION

A proven and effective means for CO, VOC, and NOx control among natural gas fueled lean-burn engines is catalytic oxidation with selective catalytic reduction (SCR). If the raw biogas is cleaned sufficiently and effectively, there is no danger of fouling any post combustion catalyst by siloxane deposition.

Catalytic oxidation removes CO and VOC upon its contact with the catalyst. Oxidation catalysts contain precious metals that react incoming CO and VOC with oxygen to produce CO_2 and water vapor. Reductions greater than 90% in CO and VOC emissions are typical with this technology.

SCR can be used with lean-burn engines since the higher oxygen concentrations in the exhaust preclude the use of less costly nonselective catalytic reduction (NSCR). SCR requires the injection of urea to react with the NOx in the engine's flue gas, and is very effective in its removal. The SCR catalyst promotes the reaction of ammonia with NOx and oxygen, with water vapor and nitrogen gas being the end products.

The demonstration project at OCSD has shown with certainty that this combination of post combustion systems (oxidation catalyst and SCR) is capable of handling treated biogas combustion for multi-pollutant control. The District issued a grant to OCSD in 2009 (*SCAQMD Contract #10114*) to support the pilot test study of Engine No. 1 (in Fountain Valley) with a catalytic oxidizer/SCR with digester gas cleanup, and the operation of the pilot study was granted a Permit to Construct/Operate for an Experimental Research Project by SCAQMD (Application Number 497717) in November 2009. The construction and installation of the pilot study equipment commenced in October 2009; the pilot study testing officially began on April 1, 2010 and officially ended on March 31, 2011. A continuous emission monitoring system (CEMS) was used for analysis of NOx and CO emissions. Sampling methods for other pollutants are listed in Table 2 below.

Table 2. Sampling Methods for Pollutants in OCSD Pilot Study

Pollutant	Sampling Method
CO	CEMS, Portable Analyzer, SCAQMD Method 100.1
VOC	SCAQMD Methods 25.1/25.3
NOx	CEMS, Portable Analyzer, SCAQMD Method 100.1
Aldehydes	Modified CARB Method 430, SCAQMD Method 323 (Formaldehyde)
Free Ammonia (Ammonia slip)	Modified SCAQMD Method 207.1 and Draeger® tubes

The results of the pilot study are as follows:

1. NOx emissions averaged around 7 ppmv, well below the proposed rule limit of 11 ppmv by over 35 percent.
2. VOC emissions averaged around 3.6 ppmv, well below the proposed rule limit of 30 ppmv by 88 percent.
3. CO emissions averaged around 7.5 ppmv, well below the proposed rule limit of 250 ppmv by 97 percent.

The maximum VOC level reached was around 5 ppmv, while the maximum CO level reached was 42 ppmv. There were some NOx excursions during the testing period, however, and these accounted for 0.9% of the total 15 minute measurement periods. The results were based on a 15 minute averaging time, per the current rule requirements. Staff analyzed several possible averaging times to determine an acceptable time period that would address the exceedances without affecting mass emissions. Using OCSD's 15-minute raw data from its pilot study, several averaging times were analyzed. Staff found that an 8 hour block-averaging time would address OCSD's exceedances above 11 ppmv. As a result of this analysis, Staff is proposing a 12 hour averaging time, based on a rolling average, to be able to comfortably address NOx exceedances without affecting the overall mass emissions. With the results obtained, the OCSD project has demonstrated that this type of control technology can prove effective for meeting the proposed Rule 1110.2 limits.

A consideration that is always taken when applying SCR technology is the potential for ammonia slip when injecting urea into any exhaust gas stream. Ammonia is a toxic compound, and careful control must be taken in order to prevent excess amounts from escaping out of the stack. A limit of 10 ppm was assigned on the project's research permit and the maximum level emitted was 5 ppm during the pilot demonstration. An important factor when adjusting urea injection rates is ensuring that sufficient amounts of urea are injected in response to the engine's load demand and/or NOx level in real time or as close to real time as possible. This is to prevent too much ammonia from slipping out of the stack while also simultaneously preventing too little urea from entering the exhaust stream that can result in an increase in NOx out of the stack.

An installation that also uses an oxidation catalyst/SCR technology, but applied to a landfill, is located at the Ox Mountain Landfill in northern California (Figure 2). One of six GE-Jenbacher engines on-site was retrofitted with both a catalytic oxidizer and SCR system in 2009 and has been operating since. Data that has been obtained from the BAAQMD has shown that the proposed Rule 1110.2 limits are achievable. CEMS data obtained from 2010 shows a consistent performance level that is consistent with OCSD's pilot study. In addition, monthly emission data shows that the emissions limits are being achieved on an average mass per brake horsepower hour basis.

Figure 2. Ox Mountain's Landfill Gas to Energy Facility in Half Moon Bay, CA

NOXTECH

NOxTech is another post combustion control technology which is non-catalytic, does not require gas cleanup, and is capable of achieving multi-pollutant control of NOx, VOC, and CO. Engine exhaust gases enter the unit where the temperature is raised by a heat exchanger. The gases then enter a reaction chamber where a small amount of the engine's fuel is added to raise the gas temperature to 1400-1500°F. At this temperature in the reaction chamber, NOx reduction can occur using urea injection, while CO and VOC are simultaneously incinerated. The system is designed to handle biogas that is of a lower BTU content than higher BTU content natural gas.

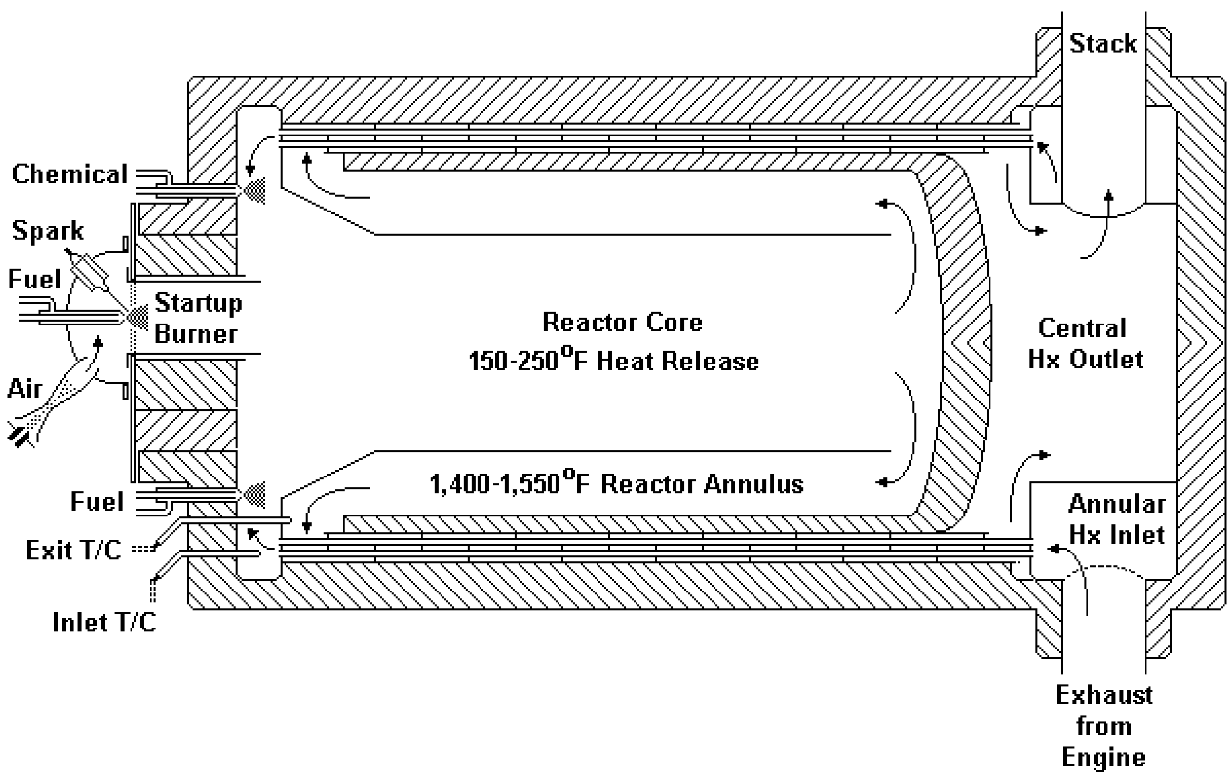


Figure 3. NOxTech System

In May 2010, Eastern Municipal Water District (EMWD) installed a NOxTech unit at its Mills Pumping Station in Riverside. This site operates three natural gas fired internal combustion engines and the NOxTech unit is capable of handling the exhaust gas streams for multiple engines. While originally designed to treat exhaust gases from biogas engines, EMWD opted to test the NOxTech system with its natural gas-powered engines. The NOxTech system installed downstream of natural gas-powered engines at EMWD experienced some setbacks and was not able to achieve NOx levels that were in compliance with the proposed 11 ppmv rule limit in 2011 because the system was operating at higher than expected temperatures, resulting in higher than expected thermal NOx formation. A variance was granted by the AQMD for the installation and additional testing of an Exhaust Gas Recirculation (EGR) system that is designed to lower the temperature enough to prevent excess NOx formation. This enhanced system will commence testing in February 2012. Contingent to the results of this installation, a second NOxTech unit is set to begin construction at the EMWD Temecula facility's digester gas-fired engines later this year.

A NOxTech system can be a less costly installation that a traditional catalytic oxidation/SCR installation due in large part to the anticipated decreased operations and maintenance (O&M) costs. Intermittent sorbent and catalyst replacements are a significant portion of the O&M costs incurred with the operation of a catalytic oxidation/SCR system. A NOxTech system eliminates the need for sorbents and catalysts. Urea injection, however, is still a required component for a NOxTech system as well as an SCR system.

ALTERNATIVE TECHNOLOGIES

This section provides a brief description on alternative technologies that can be utilized to produce power from biogas with a much lower criteria pollutant emissions profile than that of biogas-fueled IC engines.

Fuel Cells

Fuel cells are an emerging technology capable of producing power with very low pollutant emissions without the utilization of combustion. In fact, fuel cells can produce electricity much more efficiently than combustion-based engines and turbines.

A fuel cell uses a molten carbonate cell to create an electrochemical reaction with the inlet biogas at the anode and oxygen from air at the cathode. Hydrogen is created in a reforming process at the anode, while carbonate ions are created at the cathode. The hydrogen gas reacts with the carbonate ions to produce water and electrons. These electrons flow through an external circuit that produces the electricity for the power plant.

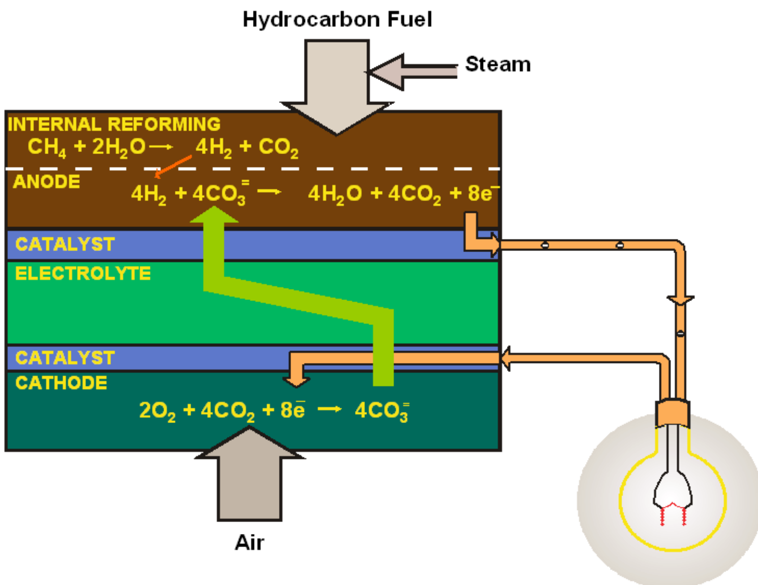


Figure 4. Fuel Cell Chemistry for Power Generation

These electrochemical reactions are produced in individual molten carbonate electrolyte stacks. The stacks are modular in design, so the total power production capacity of the generating plant can be tailored to accommodate several fuel cell stacks to meet the desired power output. The heat generated by the fuel cells can also be recovered and used to provide process heat. For instance, the recovered heat can be used to supply heat to a wastewater treatment plant's anaerobic digesters. The fuel cell stacks, however, are sensitive to impurities, so a gas cleanup system is critical to maintain the performance of the fuel cell stacks. Siloxanes, particularly, can foul a fuel cell.

There are many fuel cell installations that run on natural gas, and there are also several in California that operate on biogas. There are two installations in the basin located at wastewater treatment plants that are designed to operate on biogas from anaerobic digesters. EMWD has installed a fuel cell power generating facility at the Moreno Valley Regional Water Reclamation Facility. The City of Riverside has also installed a fuel cell system at its wastewater treatment plant. Inland Empire Utilities Agency (IEUA) has begun construction of a fuel cell plant at its regional plant in Ontario. The installations at EMWD and the City of Riverside have encountered some issues with the early design fuel cells. Specifically, the stacks are not producing the electrical output they are rated for. Fuel Cell Energy (FCE), the equipment manufacturer, is currently in the process of replacing the fuel cell stacks at both facilities. Those fuel cell power plants are set to restart later this year.

Flex Energy

Flex Energy is a system that combines microturbine technology with that of regenerative thermal oxidation to produce power with a ultra low emissions profile and without the necessity of biogas cleanup. The system is capable of taking low BTU content biogas that would be otherwise incombustible by any engine or turbine and diluting it before introducing it to the thermal oxidizer that raises the temperature to destroy VOC and CO. The thermal oxidizer's temperature is also not raised so high as to facilitate the formation of thermal NOx. This process results in the consumption of methane gas without the pollutants from traditional combustion.

A typical internal combustion engine that runs on landfill gas will struggle if the methane content of the biogas drops below 35-40%. Landfills that produce gas with a methane content lower than what an engine can use will typically send the gas to a flare for combustion. An advantage of the Flex Energy system is that it is capable of handling biogas with a methane content similar to what an engine consumes down to a level that is outside an engine's range of consumption. An open landfill will produce gas with a more or less constant amount of methane, roughly 50%. The other 50% is typically CO_2. However, once a landfill ceases to accept municipal solid waste, the amount of gas produced by the landfill will begin to decay gradually. A Flex Energy system can consume landfill gas well after a landfill closes and well after an engine ceases operation because of the low methane content.

Another advantage with this type of system is that it does not require a fuel cleanup system for siloxanes and other impurities. Like the fuel cells, these systems can be modularly applied, based on the inlet characteristics of the biogas and desired power output.

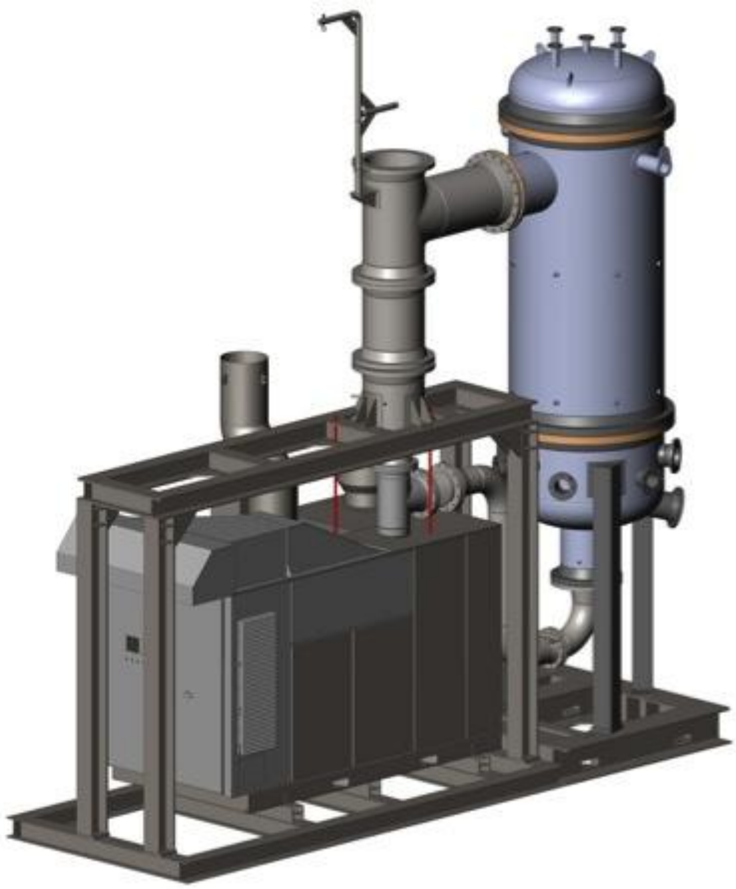


Figure 5. Flex Energy FP250 Flex Powerstation

A pilot study of a Flex Energy installation was recently successfully completed at Lamb Canyon Landfill in Riverside County, CA. A Flex Energy installation is currently collecting data at a landfill in Fort Benning, GA, while approval has been granted for another installation at the Santiago Canyon Landfill in Orange County.

Other Combustion Technologies

Traditional turbines, boilers and flares fall under this category. Several landfills in the basin currently employ the use of turbines for the combustion of the biogas and also require extensive gas cleanup to protect the turbine blades from siloxane buildup. For example, the Calabasas Landfill operated by Los Angeles County Sanitation District and the Brea-Olinda Landfill currently use turbine technology with gas cleanup for handling landfill produced biogas. Traditional boilers can also process biogas and currently are being used by both landfills and wastewater treatment plants across the basin. For example, if a facility that operates both engines and boilers chooses to shut down its engines, the remaining biogas can usually be handled by its boilers and any excess can be routed to the facility flare, if necessary. Boilers are less sensitive to impurities and do not require extensive gas cleanup. The last resort for any facility that handles biogas, but cannot combust it because of an insufficient quantity, would be to flare it. With flaring, a facility can achieve VOC destruction from combustion, while many newer BACT flares achieve low NOx emissions. However, there are some possible CO_2 emission impacts from a greenhouse gas perspective and these will be discussed in another section of this document. Figure 6 shows a comparison between source test average emissions among different technologies. Boilers, gas turbines, and microturbines overall have lower emission profiles than IC engines.

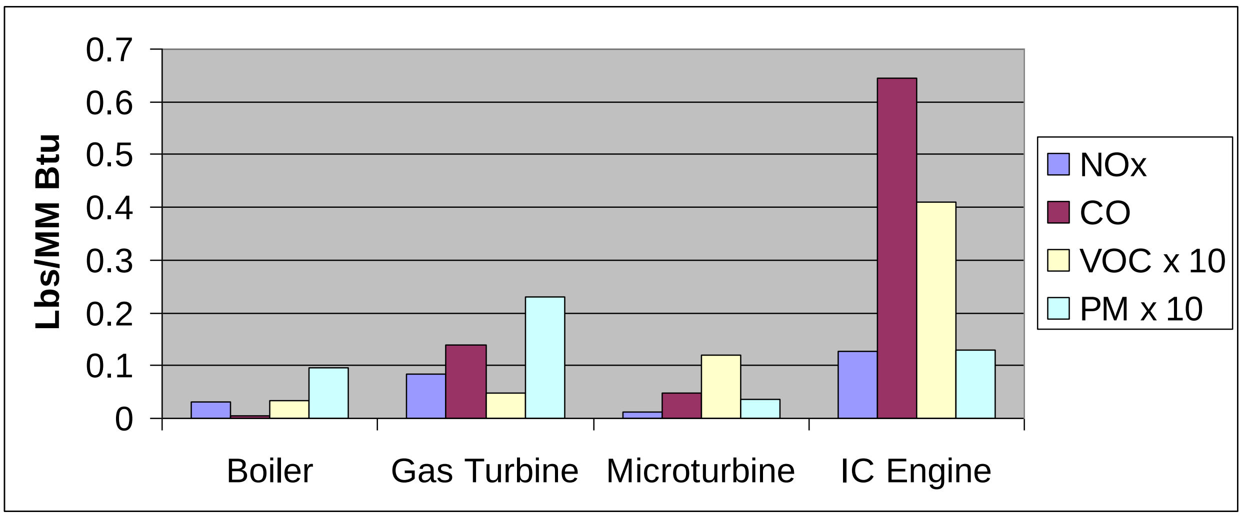


Figure 6. Emissions Comparison Among Different Biogas Electric Generation Technologies

COST EFFECTIVENESS

The costs effectiveness analysis for this report relies on real data obtained from OCSD demonstration project. The pilot study demonstration project at OCSD is an example of an achieved in practice installation that has produced favorable results and that is cost effective. This installation used a digester gas cleanup system with a catalytic oxidizer and SCR for post-combustion emissions controls. In OCSD's case, additional structural work was required to support the placement of the catalytic oxidizer and SCR units. An overhead steel platform had to be constructed to support the equipment while allowing vehicle traffic to proceed underneath, primarily to allow for urea deliveries.

The capital costs included the supporting steel necessary for the platform construction, while the annual operating costs included digester gas cleaning media replacement, oxidation catalyst and SCR catalyst replacement, and urea replacement. As a result of the gas cleanup system providing cleaner biogas to the engine, subsequent O&M costs to the engine itself were reduced as well as the frequency of maintenance intervals.

Emissions reductions are calculated from the current Rule 1110.2 rule limits to the proposed Rule 1110.2 limits. Emissions are calculated for NOx, VOC, and CO. For calculating cost effectiveness, the AQMD uses the Discounted Cash Flow (DCF) model, which takes into consideration both capital cost plus annual operating and maintenance costs. This use of this model is consistent with previous rulemaking proposals and past control measures because it links the cost of the project with its environmental benefits. The equipment is given a twenty year life and a 4% interest rate. The calculated present worth value (PWV) is then divided by the summation of the emission reductions over the length of the project (20 years). The emission reductions for CO are discounted by one seventh because of its ozone-formation potential is approximately one seventh from that of NOx.

The 2008 Interim Technology Assessment provided preliminary cost information for a non-regenerative siloxane removal system with oxidation catalyst and SCR. Table 3 provides a comparison between the cost estimates from the Interim Report and those obtained from OCSD's Final Report on its pilot study.

Table 3. Comparison of OCSD's Costs for Pilot Study Installation and Operation

	Interim Report	Final Report
Installed Equipment, $	1,265,000	1,989,529
Equipment minus Catalyst, $	*1,096,000*	*1,875,129*
Catalyst Cost, $	*169,000*	*114,400*
Project Management & Installation Supervision, $	285,000	298,429
Total Initial Investment, $	**1,550,000**	**2,287,958**
Sorbent Replacement, $/yr	62,000	40,000
Catalyst Replacement, $/yr	56,000	38,133
Reactant, $/yr	15,238	18,900
Reduced Power Production, $/yr	2,363	1,200
Equipment Maintenance, $/yr	-7,440	-30,147
Total Annual Cost, $	**128,161**	**58,950**
Present Value of 20-yr Cost, $	**3,360,916**	**3,089,089**
NOx Reductions	15.18	10.7
VOC Reductions	2.20	14.6
CO Reductions	0	64.9
Cost Effectiveness ($/ton NOx+VOC+CO/7)	**11,100**	**4,500***
$/kW-hr	**0.08**	**0.01**

*This figure is based on permit-specific limits that are lower than the current Rule 1110.2 limits.

The actual capital costs were higher than was estimated in the Interim Report, but the operation and maintenance costs were actually lower due to the reduced engine maintenance and emission fee credits from the lower emissions.

The calculated cost effectiveness of OCSD's 3471 bhp engine is $4,500 per ton of NOx, VOC, and CO/7. The installation and operating costs for OCSD's system were scaled across a series of varying digester gas engine sizes representative of the current population. OCSD's cost effectiveness was calculated based on 6,000 annual operating hours for the pilot study, while the cost effectiveness for the other engines was based on 8,000 operating hours. 8,000 hours was used as a typical usage level for the engines analyzed for the Interim Report. Table 4 summarizes these results. OCSD's permit limits for its demonstration project engine had permit limits of 45ppmv NOx, 209 ppmv VOC, and 590 ppmv CO. The cost effectiveness calculated for the rest of the engines is based on the current rule limits of 36 ppmv NOX, 250 ppmv VOC, and 2000 ppmv CO. The majority of the permit limits for the digester gas engines in the AQMD inventory are in line with the current biogas rule limits for digester gas engines. Some facilities use the efficiency correction factor (ECF) to operate at a slightly higher NOx limit, for example. Other biogas engine permits have lower VOC and/or CO limits than in the current rule. Cost effectiveness becomes less favorable with a smaller project size, especially if the full scale costs are applied, so the scaling of the costs explores this scenario of using the costs of an actual installation and applying it to a range of smaller engine sizes. Based solely on engine size, OCSD's cost effectiveness for a 3,471 bhp engine should really be lower than what is calculated for a 1,600 bhp digester gas engine, but the lesser reductions due to the lower permit limits elevate the costs. A sensitivity analysis was conducted in an effort to explore an upper bound cost effectiveness scenario for a smaller engine of 500 bhp by assuming the control costs to equal the full scale costs incurred by the 3,471 bhp engine in OCSD's pilot project. The cost effectiveness for this scenario was estimated at $10,900 per ton of NOx, VOC, and CO/7 reduced. Project size and back pressure considerations can play a large part into the capital expenses of retrofitting with and oxidation catalyst/SCR. This scenario is presented to show the cost effectiveness for a small engine with a significant capital outlay. Consequently, costs for additional equipment to compensate for back pressure may have been subsumed in this overly conservative cost analysis.

Table 4. Cost Effectiveness for Digester Gas Engines Based on OCSD's Actual Costs

BHP	1600	1000	600	500	500 (unscaled)
Installed Equipment, $	1,230,965	921,665	673,883	602,807	1,989,529
Equipment minus Catalyst, $	*1,178,231*	*888,707*	*654,108*	*586,328*	*1,875,129*
Catalyst Cost, $	*52,734*	*32,959*	*19,775*	*16,479*	*114,400*
Project Management & Installation Supervision, $	137,565	85,978	51,587	42,989	298,429
Total Initial Investment, $	**1,368,529**	**1,007,643**	**725,469**	**645,796**	**2,287,958**
Sorbent Replacement, $/yr	18,438	11,524	6,914	5,762	40,000
Catalyst Replacement, $/yr	17,578	10,986	6,592	5,493	38,133
Reactant, $/yr	8,712	5,445	3,267	2,723	18,900
Reduced Power Production, $/yr	1,089	681	408	340	1,200
Equipment Maintenance, $/yr	-13,897	-8,685	-5,211	-4,343	-30,147
Total Annual Cost, $	**31,921**	**19,951**	**11,970**	**9,975**	**58,950**
Present Value of 20-yr Cost, $	**1,802,338**	**1,278,774**	**888,148**	**781,361**	**3,089,089**
NOx Reduction, tpy	4.8	3.00	1.8	1.50	1.50
VOC Reduction, tpy	11.1	6.90	4.1	3.50	3.50
CO Reduction, tpy	205.3	128.3	77	64.2	64.2
CO Reduction/7, tpy	29.3	18.3	11.0	9.2	9.2
Cost Effectiveness, $ per ton of NOx+VOC+CO/7	**2,000**	**2,300**	**2,600**	**2,800**	**10,900**
$/kW-hr	**0.01**	**0.01**	**0.01**	**0.01**	**0.05**

OCSD's actual equipment costs (gas cleanup, oxidation catalyst, SCR) and operating costs were also applied to landfill gas engines to determine their cost effectiveness. The equipment costs were increased to account for the higher inlet gas volume per BTU supplied to the engine. Also, the annual operating hours for the 3,471 bhp engine was increased to 8,000 annual operating hours to represent a landfill engines operation. The resulting cost effectiveness for landfill engines is summarized in Table 5.

Table 5. Cost Effectiveness for Landfill Gas Engines Based on OCSD's Actual Costs

BHP	3471	2700	2000	1500
Installed Equipment, $	2,082,529	1,781,763	1,479,753	1,239,133
*Equipment minus Catalyst, $**	*1,968,129*	*1,692,774*	*1,413,835*	*1,189,695*
Catalyst Cost, $	*114,400*	*88,989*	*65,918*	*49,438*
Project Management & Installation Supervision, $	298,429	232,140	171,956	128,967
Total Initial Investment, $	**2,380,958**	**2,013,903**	**1,651,708**	**1,368,100**
Sorbent Replacement, $/yr	40,000	31,115	23,048	17,286
Catalyst Replacement, $/yr	38,133	29,663	21,972	16,479
Reactant, $/yr	18,900	14,702	10,890	8,168
Reduced Power Production, $/yr	1,200	1,069	792	594
Equipment Maintenance, $/yr	-30,147	-23,451	-17,371	-13,028
Total Annual Cost, $	**58,950**	**53,098**	**39,332**	**29,499**
Present Value of 20-yr Cost, $	**3,182,089**	**2,735,510**	**2,186,232**	**1,768,992**
NOx Reduction, tpy	10.5	8.1	6	4.5
VOC Reduction, tpy	1.1	0.8	0.6	0.5
CO Reduction, tpy	445.4	346.4	256.6	192.5
CO Reduction/7, tpy	63.6	49.5	36.7	27.5
Cost Effectiveness, $ per ton of NOx+VOC+CO/7	**2,100**	**2,300**	**2,500**	**2,700**
$/kW-hr	**0.01**	**0.01**	**0.01**	**0.01**

*The equipment costs were increased by $93,000 to account the siloxane cleanup system's processing of a greater gas volume per BTU supplied to the engine

Cost data was also received from the Bay Area AQMD for the installation at Ox Mountain Landfill's 2,677 bhp engine with regenerative temperature swing adsorption (TSA) gas cleanup, oxidation catalyst, and SCR (Table 6). There are six total engines at that facility. Cost effectiveness was calculated from SCAQMD rule limits to the proposed rule limits, operating 8,000 hours per year. There is an increased capital cost for a regenerative TSA system with a higher annual operating cost outlay, but the total gas cleanup cost was divided by 6 to arrive at a per-engine estimate. The annual costs presented here do not reflect any credit taken for reduced engine maintenance, so the actual operating costs may be lower than those in Table 6.

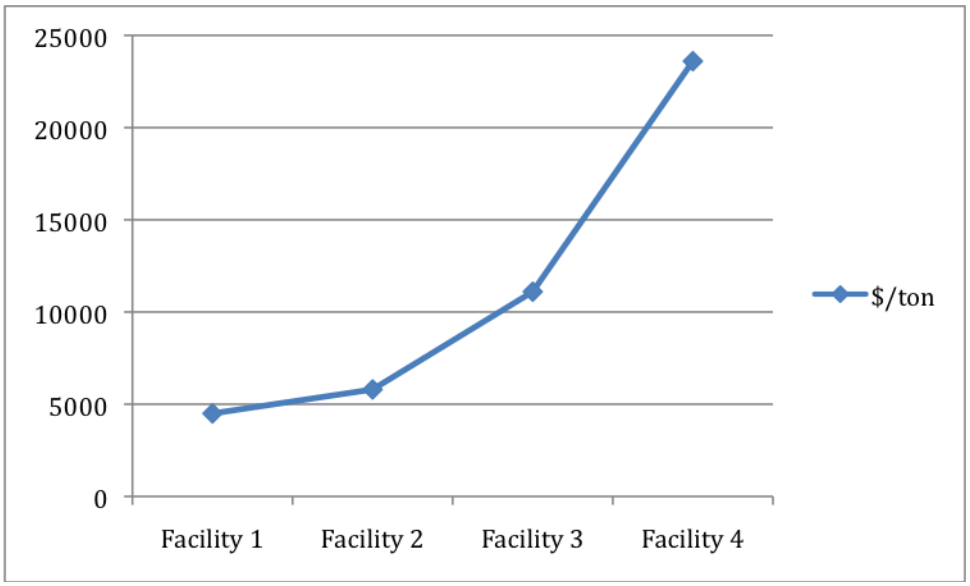
Table 6. Cost Effectiveness of Landfill Installation with Regenerative Gas Cleanup, Oxidation Catalyst, and SCR

*Capital Costs**	
TSA System, $	271,544
TSA Installation, $	91,480
TSA Flare, $	25,105
TSA Flare Install, $	6,699
SCR System, $	46,218
SCR Install, $	28,960
Ox Cat System, $	38,218
Ox Cat Install, $	28,377
CEMS, $	170,165
CEMS Install, $	20,080
Design & Eng (3.4% of equip), $	18,742
Const & Comm (8% of equip), $	44,100
Total Installed Cost, $	**789,688**
Operating Costs	
TSA, $	84,000
Flare, $	17,500
CEMS, $	34,600
SCR, $	51,394
Ox Cat, $	12,514
Labor, $	60,000
Electricity, $	52,740
Total Annual Op Costs, $	**312,749**
PWV (20 yrs @4%), $	**5,039,941**
NOx Reduction, tpy	8.1
VOC Reduction, tpy	0.8
CO Reduction, tpy	343.5
CO Reduction/7, tpy	49.1
Cost Effectiveness, $ per ton of NOx+VOC+CO/7	**4,300**
$/kW-hr	**0.02**

*TSA system costs were divided by 6 to reflect a per-engine basis estimate

The cost effectiveness estimates presented here are within the range of cost effectiveness estimates presented to the Governing Board for past rulemakings. Digester gas and landfill gas engines of all sizes are shown to be cost-effective. The dollars per kilowatt-hour estimates (which assume a 97% generator efficiency) also show that the addition of emission controls is cheaper than the cost of electricity from the grid which runs about 8 cents per kilowatt-hour. District staff has solicited cost information from all thirteen biogas facilities and operators, but has received detailed costs from only four of these facilities. Based on the costs provided by the four facilities, the current cost effectiveness range using the DCF model is $4,500 to $23,500 per ton of NOx, VOC, and CO/7. This range is illustrated in Figure 7. Staff is currently working with the remaining facilities to receive more detailed costs so that a more complete cost effectiveness range can be provided.

Figure 7. Cost Effectiveness Curve for Facility Provided Estimates



From the lessons learned from the technology demonstration projects, technology is available that can achieve significant reductions in NOx, VOC, and CO. The proposed limits of Rule 1110.2 are feasible and cost effective. The excursions experienced by OCSD's demonstration project can be managed by a longer averaging time, thus the NOx limits can be consistently achieved.

GLOBAL WARMING IMPACTS

The Adopting Board Resolution for the February 1, 2008 amendment of Rule 1110.2 directed AQMD staff to prepare a Technology Assessment including a summary of potential trade-offs between greenhouse gas (GHG) and criteria pollutant emissions due to the adoption of the proposed biogas emission limits (NOx limit of 11 ppm (referenced to 15% O_2), VOC limit of 30 ppm and CO limit of 250 ppm). Operation of the IC engines using biogas to produce electrical power generates the three criteria pollutants

NOx, VOC and CO. If the operators of those engines elect to cease power generation then the biogas must be flared or redirected to another usage onsite including fueling boilers. The choice to generate power or not leads to a trade-off: upgrade the power generation emissions controls to obtain a cleaner emissions profile or potentially shutdown the internal power generation and flare but in doing so release more greenhouse gases. The following discussion provides a comparison of the impacts the two options present: criteria pollutant emissions and greenhouse gas emissions from operation of the IC engines vs. flaring.

Criteria Pollutant Impact

Figures 8 through 10 compare emissions of criteria pollutants from existing engines, an engine meeting the proposed limits and biogas flares at facilities affected by the proposed biogas emission limits. The range of flare emissions shown in the following figures represents the variety of permit limits and operating conditions for flares at affected facilities. The permit emissions limits vary because the age of flares at these facilities ranges from less than 10 years to 40 years old. The emissions for each technology include the direct emissions from fuel combustion (natural gas). The flare emissions also include the criteria emissions from local utility power plants when biogas is directed to flares instead of being used to generate electricity using IC engines.

The NOx, VOC and CO emissions comparisons depicted in Figures 8 through 10 are expressed as a percent compared to the proposed engine emission limits – a ratio of the current and proposed emission limits in ppm or pounds of emissions per Btu of fuel consumed. In addition, Figures 8 and 9 show the range of the current NOx and VOC emission limits for large and small engines. Also included in the three figures are the estimates of flare emissions and the emissions from a large powerplant. These emissions are included because when an engine is shut down, the replacement electricity is assumed to be generated by a local utility boiler or combined cycle turbine.

The comparison of criteria pollutant emissions from engines and flares uses the ratio of the emission limit for the specific technology to the emission factor for an engine meeting the proposed biogas emission limits (NOx limit of 11 ppm (referenced to 15% O_2), VOC limit of 30 ppm and CO limit of 250 ppm). This ratio is then converted to percent with the proposed engine limit set at 100%. This ratio can be generated by converting all emission limits to parts per million at 15% O_2 (the reference level for the Rule 1110.2 emission limits) or by converting all emission limits to pounds per million Btu.

The emission comparisons assume that the biogas is diverted to flares from engines and there is an equivalent amount of electricity produced by local power plants meeting current BACT. Compared to flares, power plant criteria pollutant emissions are smaller because limits are very low and base load power plants use one-half of the fuel of engines to produce the same amount of electricity. These emissions are included in Figures 8 to 10 as part of the flare emissions. While there are other sources of electricity outside the AQMD, the amount of electricity produced by biogas engines is small in comparison and local base load power plants have enough capacity to replace these sources at a cost-effective price.

As presented in the Figures 8 through 10, the option to flare emissions would generate less criteria pollutant emissions than are currently produced under the existing emissions limits, regardless of flare configuration. Operating the IC engines at the proposed limits would be cleaner for NOx and VOC than venting emissions to the Pre-1998 flares (which include the required base load emissions). In each case, flaring using a BACT flare, including the base load emissions would generate fewer emissions than for IC engines operating within the proposed new emissions limits. However, the option to flare raises illuminates the counterpoint argument: Does flaring result in a greater GHG emissions impact than generating internal power?

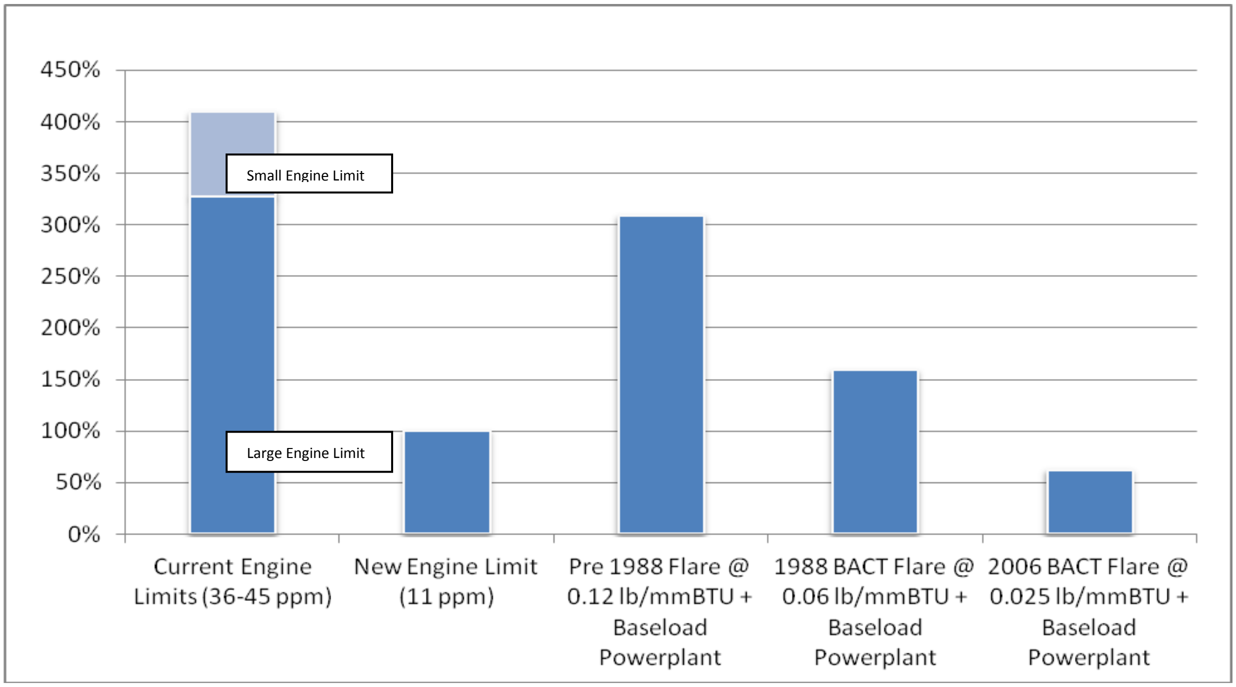


Figure 8

Biogas Flare and Engine NOx Emissions Compared to a 11 PPM Emissions Limit

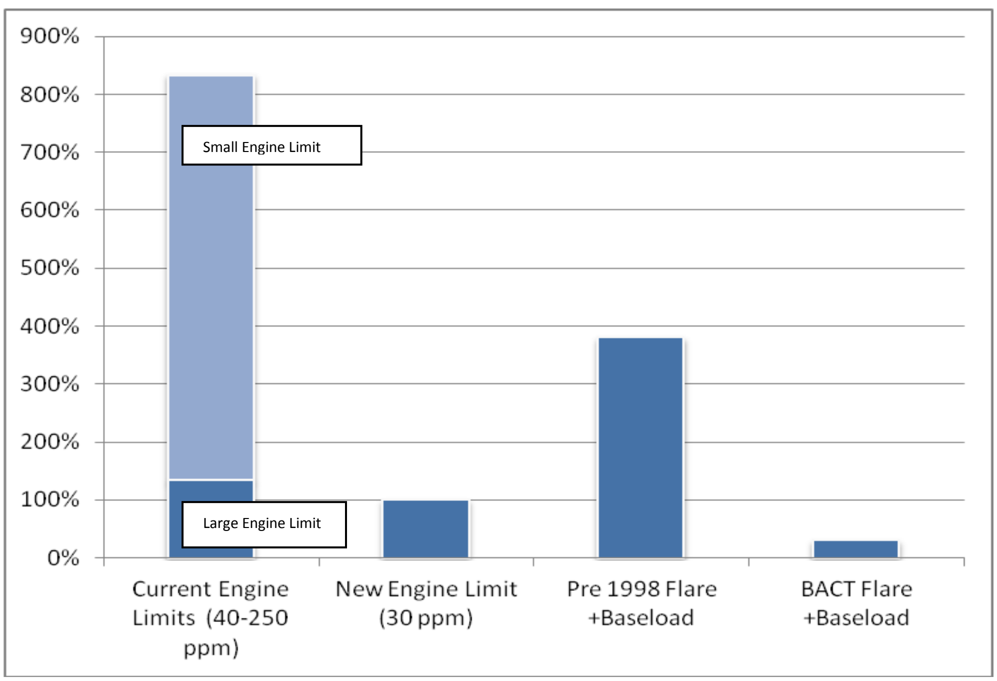


Figure 9

Biogas Flare and Engine VOC Emissions Compared to a 30 PPM Emissions Limit

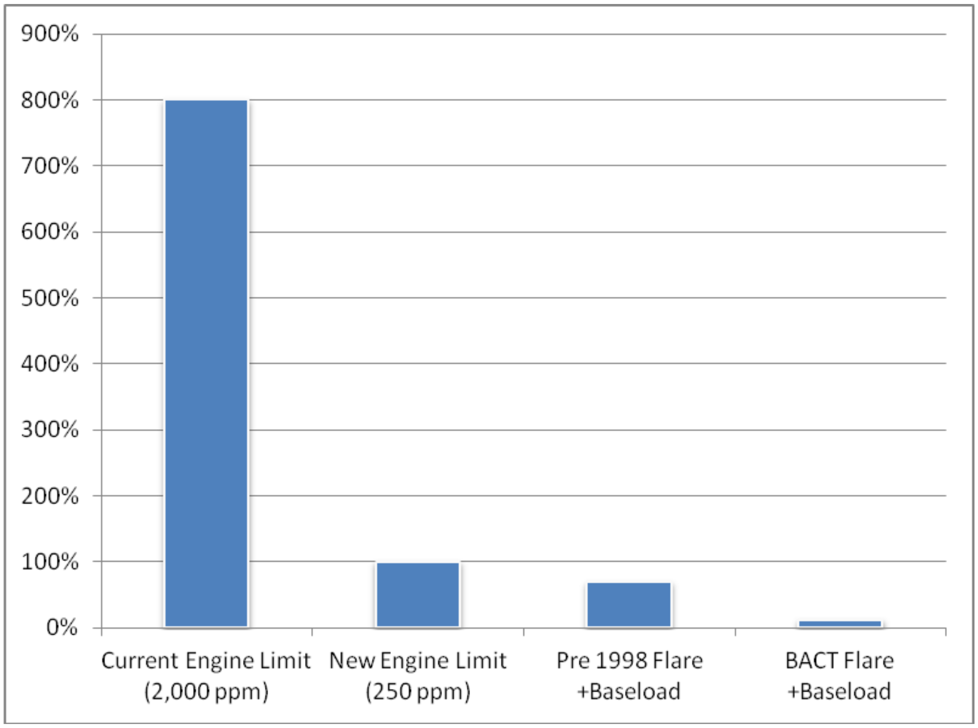


Figure 10

Biogas Flare and Engine CO Emissions Compared to a 250 PPM Emissions Limit

Greenhouse Gas Impacts

Figure 11 provides a comparison of greenhouse gas emissions impact from engines, flares and base load power generation. The figure includes emissions from engines using different amounts of supplemental fuel (natural gas), powerplants and newer versus older flare technologies. The differences in GHG emissions are expressed as percent compared to biogas engine emissions. The GHG emission comparison in Figure 11 is based on carbon dioxide equivalents (CO_2e). Emissions of gases that contribute to global warming are represented as CO_2 equivalents by taking into account their warming potential in the atmosphere relative to CO_2. For example, methane (CH_4) is assigned a warming potential of 21 times CO_2 (over a 100 year timeframe).

More specifically, the comparison of GHG emissions is also a ratio of each technologies emissions (expressed as carbon dioxide equivalents – CO_2e) to the CO_2e associated with an IC engine using 15% supplemental natural gas. This ratio is developed on a mass basis. In the case of an IC engine and pre-2006 flare, it is assumed that for every 100 methane molecules provided as fuel to the engine, 99 are combusted to CO_2 and one is emitted in the exhaust. The global warming potential of this one methane molecule is equivalent to 21 CO_2 molecules. In addition, 15% of the fuel methane for the base engine and pre-2006 flare scenarios comes from natural gas. The 2010 U.S. EPA method for estimating the CO_2e GHG emissions related from natural gas production and transport to an average of about 20% of the fuel Btu delivered to an operation. In 2011, EPA revised its estimate upwards to average of about 35% of the fuel Btu delivered. Using the 2011 U.S. EPA percentage translates to an additional CO_2e of 6 more molecules of CO_2 due to production and transport of that natural gas. The summation of these emissions in terms of CO_2 equivalence results in an impact of 126 CO_2 molecules for every 100 molecules of methane provided to the engine.

The same methodology is used to generate the CO_2e emissions from an engine using 50% supplemental natural gas with the same Btu content, a flare meeting current BACT limits and a base load power plant generating the same amount of electricity as the IC engine (using ½ the Btu of an engine). A flare meeting 2006 BACT has more complete combustion and emits half of the methane than older flares emit and does not require supplemental natural gas. These "emissions" are then used to generate a ratio with the base engine represented as 100%. In this analysis, the electricity is produced by local power plants in order to determine the worst case emissions if engines are replaced with flares. .

As depicted in Figure 11, operation of the IC engine using a 15 percent natural gas and 85 percent biogas is equivalent to 126 CO_2 molecules or a factor of 1.0 on the chart. An engine burning 50 percent natural gas has a higher ratio because of the additional production and transport contribution to the total CO_2e. Using a Pre 2006 (non-BACT) flare with the 15 percent natural gas contribution has an equivalent CO_2e signature as the biogas engine (1.0). The BACT flare and base load power generation (with the production and transport contribution to the total CO_2e) exhibit lower GHG impacts compared to the biogas engine or the Pre 2006 flare. However, if a facility elects to flare the gas with a Pre 2006 flare but acquires power from the grid, the factor approaches 1.8 or 80 percent more GHG emissions than continued operation of the IC engine. Even if a facility uses a BACT flare but needs supplemental power from the grid, the factor rises to approximately 1.5 or 50 percent GHG emissions above the continued operation of the IC engine.

GHG Impact Summary

The above analysis provides background assessments of the trade-off between achieving lower criteria pollutant emissions levels from complying with the proposed new standards and the possible GHG emissions penalty which may be incurred if a facility flares but is required to purchase power from the grid. Compared to current biogas engines, flares typically have lower criteria pollutant emissions profiles but have higher emissions of greenhouse gasses because electricity must by other sources if the biogas is not used in an engine generating electricity. Flares meeting current BACT also have a significantly lower greenhouse gas impact compared to older flares. However, new BACT flares still result in about 50% more greenhouse gas emissions than current engines (on a CO_2e basis).

In general, criteria pollutant impacts have an immediate impact on public health and as such are typically given greatest weight. GHG gas goals set by AB32 and companion legislation target the long term control strategy to address global warming. Both issues have merit and deserve attention. One additional element that needs to be noted is energy conservation and the potential wasting of an available energy source (biogas) which is neither drilled nor mined.

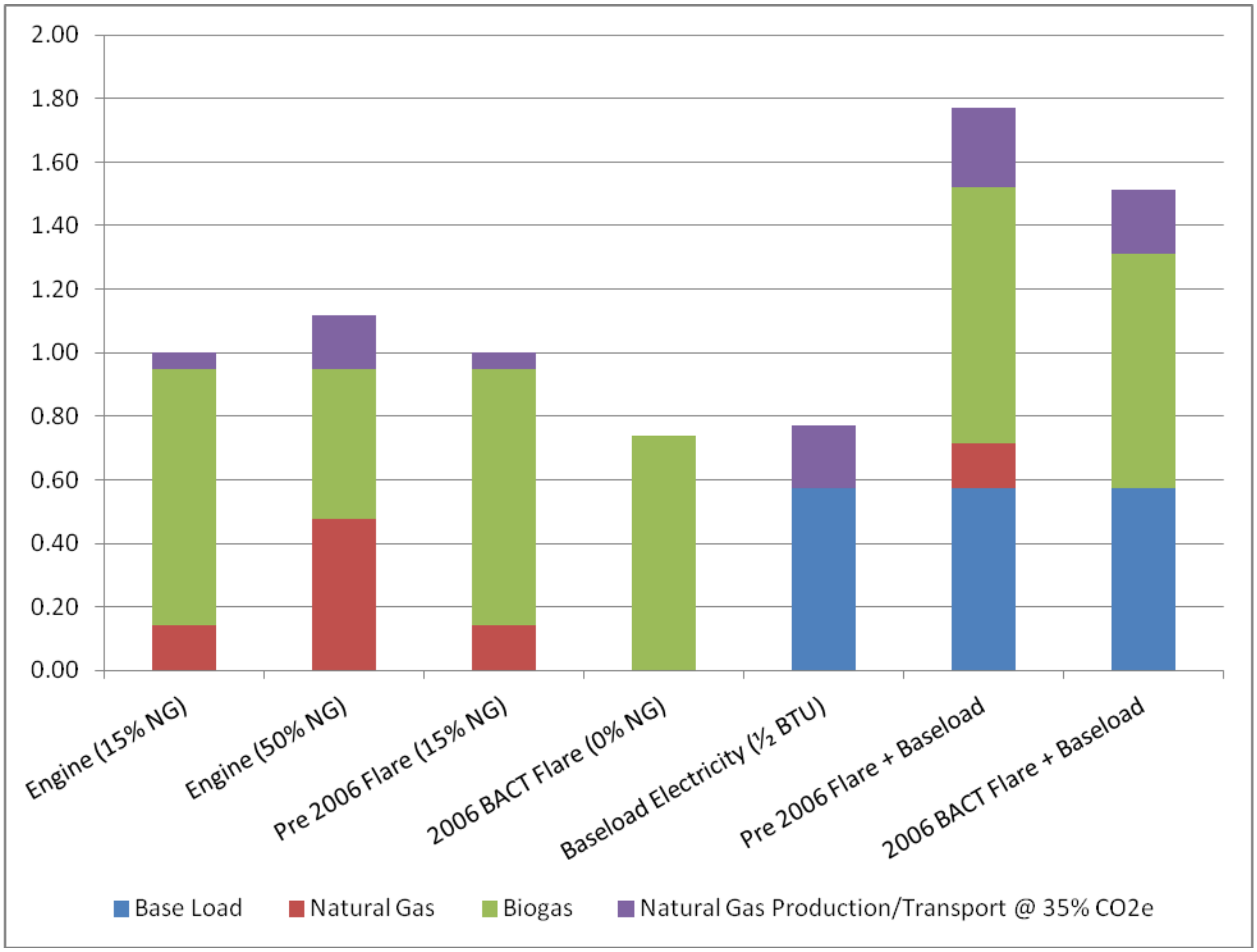


Figure 11

Comparison of CO_2 Equivalent Greenhouse Emissions from Flares and Base Load Electricity and IC Engines

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